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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP DBA ROCKY MOUNTAIN POWER'S 2013 INTEGRATED RESOURCE PLAN	**CASE NO. PAC-E-13-05** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission (Commission), by and through its attorney of record, Neil Price, Deputy Attorney General, and in response to the Notice of Filing and Notice of Modified Procedure issued in Order No. 32819 on May 30, 2013 in Case No. PAC-E-13-05, submits the following comments.

BACKGROUND

On April 30, 2013, PacifiCorp filed its 2013 Integrated Resource Plan (IRP) with the Commission. As required by Order No. 22299, PacifiCorp's filing is a biennial planning document that sets forth how the Company intends to serve the electricity requirements of over 1.7 million system-wide customers in the states of California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's Idaho service territory includes over 70,000 customers in southeastern Idaho. The complete 2013 IRP consists of four separate documents: 1) 2013 Integrated Resource Plan Volume I; 2) 2013 Integrated Resource Plan Volume II – Appendices;

3) 2013 Integrated Resource Plan Confidential Volume III; and 4) 2012 Wind Integration Study supplement.

PacifiCorp's IRP was developed through a process that included 15 public input meetings with participation from key stakeholders including public interest groups, Staff from various regulatory agencies, and representatives of various customers. The overall purpose was to develop a resource plan that will economically meet future electricity load in the service area the Company is obligated to serve while considering important risk factors. The three goals of PacifiCorp's IRP process were to: 1) determine resource needs focused on the first ten years; 2) identify the preferred portfolio of incremental supply and demand-side resources to meet this need; and 3) develop an action plan for the next two to four years required to implement the plan.

The Company identified a system capacity deficit of 824 MW starting in 2013 that increases to 2,308 MW in 2022. The Company's load obligation takes into account a 1.2 percent yearly system coincident-peak load growth rate. This average yearly load forecast is 11.3 percent lower than the load forecast used in the 2011 IRP. According to the Company, the decreased load forecasts are driven in part by increased self-generation by industry taking advantage of low natural gas prices and by load cancellations. Existing resource capacity has also been adjusted down by an annual average 113 MW between 2013 and 2016 and approximately 200 MW in years 2017 and beyond. When taking into account lower load growth rates and small reductions in existing capacity, the annual load and resource balance deficit has decreased dramatically ranging from 1925 MW in year 2013 to 3852 MW in year 2020 when compared to the 2011 IRP, thus eliminating the need for major resource acquisitions in the first ten years of the planning horizon.

From an energy perspective, PacifiCorp does not experience any deficits throughout the first ten years of the planning horizon during off-peak hours. Minor deficits begin to occur during on-peak hours in 2018 and become increasingly frequent beyond the 2022 time frame.

The Idaho and system retail sales growth that drives resource needs is depicted in the table below. Compared to system sales growth, the Company predicts Idaho residential and commercial growth will exceed the system average while industrial sales growth will be less. PacifiCorp also predicts irrigation sales will decline overall for the system, with a higher rate of reduction in Idaho. Overall, the forecast shows a 0.89 percent growth rate across the planning horizon's first ten years, with Idaho's growth lagging below the system average at 0.57 percent.

Retail Sales Load Growth by Customer Class (2013-2022)

	Residential	Commercial	Industrial	Irrigation	Lighting	Total
Idaho	1.63%	1.63%	0.06%	-0.18%	1.79%	0.57%
System	0.63%	1.04%	1.03%	-0.07%	0.05%	0.89%

PacifiCorp identified 19 core cases with different combinations of fuel price, Carbon Dioxide (CO2) price, renewable portfolio standard (RPS) requirements, Demand-side Management (DSM) assumptions, and targeted resources. Each core case was modeled across five different scenarios of the Energy Gateway project implementing various combinations of transmission line segments.[1] Overall, PacifiCorp ran 94 core-case simulations with each generating a unique resource portfolio and an associated net present value revenue requirement (PVRR) over a 20-year period.[2] A summary of the core cases is included as Attachment A.

The Company selected its preferred resource portfolio after performing risk analysis on 37 of the portfolios. The final selection was based primarily on the performance of risk-adjusted PVRR, projected cumulative carbon dioxide emissions, and supply reliability measures. Incremental resources within the first ten years include: 12 MW of combined heat and power resources, 953 MW of Class 2 DSM,[3] 149 MW of solar, and between 650 MW and 1333 MW of annual market power purchases.

PacifiCorp identified 23 action items as a result of developing the plan and from feedback received from public participants. Details of these action items are listed in Attachment C.

STAFF REVIEW

After attending PacifiCorp's public meetings and reviewing its IRP, Staff believes the Company continues to improve its IRP planning process so that it remains "state-of-the-art," while customizing its approach and adding analysis to fit changing circumstances. This allows the Company to evaluate incremental supply-side and demand-side resources resulting in a

[1] See Attachment B for a map of the various Energy Gateway scenarios modeled.
[2] Number of runs includes 19 core cases multiplied by 5 transmission scenarios. The Merchant Transmission core case was only modeled using four Energy Gateway scenarios.
[3] Class 2 DSM is PacifiCorp's designation for energy efficiency measures that conserve energy through improved end-use technology.

potentially least-cost, least-risk resource portfolio taking into consideration future uncertainty in load, electricity and fuel price, carbon price, resource availability, and regulatory constraints.

Staff's analysis focuses on the following issues:

1. Load and Resource Balance – Issues related to the load forecast and planning reserve margin.
2. Resource Portfolio Selection – Company's rationale for selecting its final preferred resource portfolio; issues related to RPS, market risk, and near term investments in transmission and coal plant emission controls.

Subsequent IRPs more effectively cover resource plans in the second ten years because there will likely be changes due to uncertainty. The resource needs can be re-studied with more accurate information prior to final resource decisions being made.

Load and Resource Balance

The Company's load and existing resource balance is illustrated in the table below. The load obligation is based on the system coincident peak load forecast adjusted by existing dispatchable load control (DSM 1), load curtailment contracts, and a 13 percent planning reserve target. Existing resources include generation from coal (6168 MW), natural gas (2556 MW), hydropower (913 MW), renewable sources (121 MW), and PURPA qualifying facilities (171 MW) with the balance of resources in the form of purchased power contracts (1487 MW) net of off-system sales and reserves.[4] Existing resource capacity net of system load obligation shows a positive reserve margin of 4.4 percent in 2013 becoming negative starting in year 2016 and beyond. In all years, this is far short of the Company's goal of maintaining a 13 percent planning reserve margin; consequently new resources must be added.

[4] Capacity reflected in parenthesis after each resource type is the capacity available at system peak used to determine the load resource balance. Projection into future years vary and may not reflect totals shown in Staff's table.

Load and Existing Resource Balance (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Existing Sytem Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
System Load Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserve (13% target)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Load Obligation + Reserve Target	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

Notes:
1. System resources are netted for system sales and non-owned reserves.
2. Loads are netted for interuptible loads and existing DSM.

Load Forecast

PacifiCorp's IRP uses the maximum load hour across the system each year to determine its peak demand forecast. The Company predicts its system-wide coincident peak will be about 11.3 percent lower on average across the first ten years compared to the 2011 IRP forecast, and 5.6 percent lower than the 2011 IRP Update as reflected in the table below.[5]

System-Wide Coincident Peak Load Forecast (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10 - year average
2011 IRP	10,960	11,252	11,501	11,740	11,960	12,194	12,378	12,607	12,815	13,026	12,043
2011 IRP Update	10,418	10,734	10,985	10,880	11,200	11,394	11,578	11,776	11,976	12,167	11,311
2013 IRP	10,135	10,331	10,494	10,359	10,513	10,687	10,815	10,972	11,133	11,280	10,672
% change from 2011 IRP	-7.5%	-8.2%	-8.8%	-11.8%	-12.1%	-12.4%	-12.6%	-13.0%	-13.1%	-13.4%	-11.3%
% change from 2011 IRP Update	-2.7%	-3.8%	-4.5%	-4.8%	-6.1%	-6.2%	-6.6%	-6.8%	-7.0%	-7.3%	-5.6%

Note:
1. Year 2022 data for the 2011 IRP was not available in the report and was extrapolated..

Large reductions from previous IRP forecasts occurred for several reasons. But the Company reports that 80 percent of the reduction was due to reduced load expectations in the industrial sector. First, the lingering effects of the 2008-2009 recession have dampened overall economic activity affecting growth in electricity demand across all customer classes throughout the Company's service area. Second, industrial customers in Utah and Wyoming have cancelled or postponed load requests because of: 1) inability of customers to obtain environmental permits for mine and line extension construction; and 2) increased self-generation due to lower natural gas prices, including the construction of a 270 MW self-generation facility by a major industrial customer. Third, the Company changed how it forecasts large industrial customer load. Prior

[5] Energy load differences compared to 2011 IRP (11.2%) and IRP updates (6.7%) were comparable to peak load forecast differences.

IRP's used self-reported customer data as the basis for their forecast. But the Company found these forecasts to be overly optimistic, and it has moved to a regression-based method to forecast the entire industrial class.

When Staff examined electricity forecasts in the Energy Information Agency (EIA) 2011 and 2013 Annual Energy Outlook for the Mountain West and Pacific regions, the percentage decrease in projected energy use across the same ten-year period was comparable (5-6% reduction) to the percent change in the energy forecast of this year's IRP with the 2011 IRP Update.

Staff expressed concern that PacifiCorp's load forecast in the 2011 IRP was overly optimistic. Given the reduction to the 2013 IRP load forecast, comparable reductions relative to EIA forecasts, and the methodology changes the Company has adopted, Staff believes the Company's latest forecasts are more reasonable and in-line with current circumstances.

Planning Reserve Margin

Staff believes maintaining a reasonable planning reserve margin is very important. But excessive reserves can also drive system costs higher. PacifiCorp continues to target a 13 percent planning reserve margin in this year's IRP. Staff believes this is reasonable for three reasons. First, according to the Company's analysis, cost remains relatively flat between a 12 and 15 percent planning reserve margin. However, the cost of a planning reserve margin above 16 percent increases cost dramatically because it eliminates additional market purchases as an option and instead requires the addition of a combined cycle combustion turbine (CCCT) gas resource. Second, the Company found that a planning reserve margin of 13 percent results in approximately an 8-hour loss of load in ten years, which is less than the one day in ten year industry standard. Third, these results assume no sharing of reserves outside of PacifiCorp's system. The Company estimates an additional 3.5 percent of planning reserve margin when reserves within the Northwest Power Pool are taken into account. In addition, the Company intends to participate in the California Independent System Operator (ISO) energy imbalance market that will provide additional sharing of 5-minute reserves that are incremental to the planning reserves included in the IRP.

Resource Portfolio Selection

PacifiCorp's preferred portfolio (EG2-C07a) is shown in the table below. It was derived assuming: 1) base case regional haze investments for coal plants; 2) high gas prices; 3) low coal cost; 4) no federal CO2 prices; 5) the existence of a federal and state RPS; and 6) construction of segments C, D, and G of Energy Gateway (Scenario EG2 - see Attachment B). The resulting portfolio satisfies capacity deficits with Front Office Transactions (i.e. firm market purchases of electricity) and Class 2 DSM resources during the planning horizon's first ten years. It also includes the addition of the Lakeside II gas plant in 2014, and the retirement of the Carbon coal plant and the gas conversion of Naughton Unit 3 to both occur in 2015. Small additions include combined heat and power (CHP) resources added each year up to CHP market potential and solar generation mandated by Oregon and encouraged by Utah through tax incentives. The portfolio does not include the addition of a major generation resource until 2024, when the Company expects to add a 423 MW CCCT gas plant and 432 MW of wind generation. Finally, the Company plans to use unbundled renewable energy credits (REC) to meet Washington RPS requirements prior to 2024.

	Capacity (MW)																				Total	Total
Resources	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
Planned Resource Retirements			(502)													(760)		(701)	(73)		(502)	(2,036)
Coal Plant Upgrades	13.8		338																		352	352
CCCT		645										423				661		1084			645	2,813
SCCT																181				181	-	362
Wind												432	218								-	650
CHP	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	12	24
DSM Class 1															86	19	88				-	193
DSM Class 2	114	116	103	101	97	92	90	80	79	81	67	70	67	67	69	66	63	55	57	56	953	1,590
Solar	11.56	14	17.2	16.4	17.8	13.5	13.6	13.7	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	149	304
Front Office Transactions	650	709	845	983	1102	1209	1323	1420	1191	1333	1427	1112	1304	1425	1469	1464	1472	1231	1281	1246	1,077	1,210
Net Total	791	1485	802	1102	1218	1316	1428	1515	1287	1431	1511	2054	1606	1509	1641	1648	1640	1686	1282	1500		

Notes:
1. Table is adapted and is a summary of Pacificorp IRP Table 8.7.
2. Front office transactions amounts reflect one-year transaction periods, are not additive, and totals are average for 10 and 20 year periods.
3. Coal Plant Upgrades includes Naughton Unit #3 coal plant conversion to natural gas in 2015.
4. Solar includes passive water heating and photovoltaics to meet Oregon requirements and to take advantage of Utah incentives.

PacifiCorp determined its preferred resource portfolio by developing 94 portfolios that satisfy future load and resource balance deficits (plus 13 percent planning reserve margin). The preferred portfolio was selected based on risk-adjusted present value revenue requirements, cumulative CO2 emissions, and supply reliability metrics across three levels of CO2 prices. Risk analysis was performed on 37 of the 94 portfolios by varying gas price, electricity price, regional load, hydroelectric generation, and thermal plant outages over a 20-year period. Only two of the five Energy Gateway portfolios, the Energy Gateway reference scenario (EG1 – see Attachment B) and the reference scenario plus Populus to Windstar (EG2), were evaluated due to earlier implementation dates and a more immediate need for evaluation. After results were compiled, the Company narrowed its selection to 12 portfolios primarily based on a risk-adjusted PVRR.

Of the 12 portfolios, the highest ranked risk-adjusted PVRR under both Gateway scenarios was a portfolio that was developed allowing for accelerated Class 2 DSM ramp rates beyond what the Company assumes is achievable while restricting the portfolio from using base-load thermal resources to meet capacity deficits. It also had the highest ranking for cumulative CO2 emissions and supply reliability if run under the most minimal implementation scenario of Energy Gateway. Even though it was generally the highest ranked portfolio overall, the Company selected the second highest ranked portfolio (EG2-C07) as its preliminary preferred portfolio, instead.

Staff believes this was reasonable for two reasons. First, the preliminary preferred portfolio and the accelerated DSM portfolio are nearly identical during the first ten years. The only difference is that the accelerated DSM portfolio has an increased amount of DSM Class 2 resources in lieu of firm market purchases. Staff believes the Company reasonably decided not to choose the accelerated DSM portfolio. Given that the Company does not have confidence that the ramp rates are achievable, passing on the accelerated DSM portfolio and choosing the next highest ranked portfolio would carry less risk. This gives the Company several IRP cycles to determine if the ramp rates are feasible. However, modeling accelerated DSM ramp rates gave the Company insight as to the positive effect cost-effective DSM has on risk-adjusted PVRR of a given portfolio prompting the Company to identify several action items to attempt to accelerate its Class 2 DSM programs.

Second, by not blindly making selections based on model results, the Company is demonstrating that it is using its decision support tools appropriately. Demonstrating this further, PacifiCorp augmented its preliminary preferred portfolio so that wind resources needed to meet Washington RPS requirements were replaced with unbundled RECs. The results reflect a \$116 million to \$232 million reduction in risk-adjusted PVRR compared to the preliminary preferred portfolio. Staff believes this refinement to significantly reduce revenue requirements while allowing the Company to comply with Washington State regulatory requirements.

Renewable Portfolio Standards

Although the Company must comply with state and federal regulatory requirements, Staff believes requirements imposed by a jurisdiction that drives incremental cost above the comparable resource cost should generally not be imposed on Idaho ratepayers. Because Idaho and Wyoming do not have a state RPS, the Company developed several portfolios with and without RPS requirements to understand its effect. Generally across RPS core cases, System Optimizer does not select additional wind, biomass, or geothermal resources beyond the RPS floor for each state. Depending on the specific case, those model runs with no RPS requirements include very little or no incremental wind, biomass, or geothermal generation resources. This indicates, most likely due to low capacity contribution rates,[6] that renewables are not cost effective when compared to other resources System Optimizer can choose to meet peak loads. Because Idaho does not have an RPS while other jurisdictions that do are driving higher system cost, Staff believes this should be reconciled when allocating cost to determine Idaho's share of system revenue requirements in general rate cases.

Market Risk

Incremental firm market purchases in the 2013 preferred portfolio have increased almost 31 percent compared to the 2011 IRP preferred portfolio over the 2013 thru 2022 timeframe. Although Staff does not believe the amount is unreasonable, Staff has two concerns given increased reliance on the market. First, customer exposure to electricity price risk exists if large market anomalies occur even though the Company has accurately evaluated market price risk through modeling variable electricity prices. Second, there is no guarantee that the energy will be available for sale in the market if a geographically widespread peak event occurs. Staff believes resource adequacy studies by the Northwest Power Planning Council and the Western Electricity Coordinating Council, as well as the inclusion of a 13 percent planning reserve margin, provide reasonable assurances; nevertheless, the potential for over-reliance on the market exists.

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[6] PacifiCorp peak contribution rates based on historical data are 4.2% for wind and 13.6% for solar. See 2013 Integrated Resource Plan: Volume II – Appendices, page 361.

Transmission Planning and Investment

PacifiCorp has augmented its analysis of transmission investments in the 2013 IRP in two significant ways. First, the Company started developing a System Benefit Tool (SBT) that attempts to quantify transmission benefits not captured by other IRP models. Staff is encouraged by the development of this tool, but agrees with the Company that it is still being developed and that the benefits it reports should not be fully rolled into the IRP until its accuracy is demonstrated. Second, the Company has fully integrated transmission planning into the IRP process by modeling five Energy Gateway scenarios across all 19 core cases. This allows transmission expansion plans to be evaluated simultaneously with supply-side and demand-side resources. Given the need to economically meet increasing loads and improve reliability while integrating more renewables, having a more comprehensive and accurate picture of costs and benefits will help the Company make better resource decisions.

However, Staff believes the quality and robustness of information provided by SBT is highly varied depending on the benefit being quantified. For example, Staff believes the proposed method used to quantify customer impacts due to loss of load needs improvement. The data used is anecdotal and may not reflect actual customer benefit forecasted for a specific transmission line. Generally speaking, Staff believes SBT benefits can be reported with appropriate caveats but should not be rolled into the overall IRP analysis until the error of the calculation is well understood and sufficiently small.

Regarding Energy Gateway modeling, the Company analyzed five different Energy Gateway scenarios across all 19 core cases creating 94 separate resource portfolios compared to modeling only two different alternative futures in the 2011 IRP.[7] Staff believes this is an improvement because it allows for comparison of transmission scenarios across all cases including the highest performing portfolios. Unfortunately, due to software upgrade issues, the Company only had time to model portfolios produced under Gateway Scenario's EG1 and EG2 (see Attachment B). Because construction for the remaining segments does not occur until after the 2020 timeframe, Staff believes this analysis can be done in subsequent IRP's in time to make prudent decisions.

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[7] The two cases in the 2011 IRP were the Green Resource and the Incumbent Resource cases. These were designed as bookends that promoted aggressive renewable resource acquisition and discouraged renewable acquisition, respectively.

Of the scenarios the Company was able to complete, Staff has two observations. First, the lowest mean PVRR across all CO2 levels was a portfolio that assumes no additional thermal baseload capacity, accelerated DSM ramp rates, and no Populus to Winstar transmission line (Segment D). This may indicate that accelerating and/or increasing the amount of DSM in combination with the lower capital cost of simple cycle combustion turbine (SCCT) capacity close to load may lessen the need for Segment D. Staff recommends the Company further explore these alternatives to offset the need for the new line. In the meantime, Staff believes the Company's decision to continue permitting Segment D is reasonable.

Second, renewing Staff's earlier concern about cost allocated to Idaho driven by needs in other jurisdictions, Staff calls attention to two issues related to transmission investments in the IRP. First, the Sigurd to Red Butte transmission line (Segment G) appears to be needed primarily to resolve southwestern Utah reliability issues.[8] Although the SBT shows system benefit, Staff believes the distribution of benefits to be uneven between jurisdictions and justification would be difficult based on system benefits alone. Second, Segment D appears to benefit states with an RPS more than states without an RPS due to increased access to Wyoming wind resources. As stated earlier, given that Idaho does not have an RPS, Staff believes increased documentation and support are required when the allocation of cost are not proportional to the jurisdictional benefit.

Coal Plant Emission Control Investments

PacifiCorp is currently facing large coal plant emission control investments in order to comply with federal environmental regulations. To determine the best course of action, PacifiCorp utilized the methodology from the 2011 IRP Update to conduct its Coal Replacement Study in the 2013 IRP. Focusing its analysis on compliance dates over the next two to four years, results continue to favor shutting down both Carbon Plant units, converting Naughton unit 3 to natural gas, and making investments in emission controls for Hunter unit 1, Jim Bridger unit 3, and Jim Bridger unit 4. The Company also plans to perform a similar analysis on Cholla unit 4 in a future IRP update when compliance requirements are resolved through EPA litigation. PacifiCorp did not model near-term emission investments for the Craig and Hayden units

[8] See 2013 IRP, pp. 63-64.

because the Company believes it is bound by shared ownership agreements and legal compliance requirements in combination with the fact it is not the majority owner or operator of either plant.

Addressing prior concerns about a lack of comparison to a broader set of alternatives, the Company has altered its analysis methodology by allowing each coal plant unit to be retired on the compliance date and allowing it to be replaced from the suite of supply-side resources already included in the IRP, or by converting the unit to be fueled by natural gas. The Company also performed additional analysis assuming a hypothetically extended compliance deadline can be negotiated for Bridger units 1 and 2 in exchange for a commitment to retire the units early. Staff believes the methodology and improvements made to integrate the evaluation of emission control investments in comparison to a wider range of alternatives is more robust and reasonable.

PacifiCorp's analysis of the alternative that retires coal plant units on the compliance date did not take into account the location of alternate resources that could reduce the need for additional transmission capacity. For example, Staff believes that if Jim Bridger units were shutdown early and replaced with generation closer to major load centers, a significant amount of existing transmission capacity could become available lessening and/or delaying the need for the Populus to Windstar transmission line (Segment D). Staff believes an analysis should be done and, if warranted, transmission implementation plans should be adjusted and any cost savings should be included in coal plant emission control investment decisions.

Acknowledgement

In this year's IRP, the Company requested acknowledgment for resource investments, specifically, the Sigurd-to-Red Butte transmission project. This request seems to imply some form of pre-approval; however, approval for recovery of resource investments can only be "approved" in a separate prudence review normally conducted during a formal Idaho rate case or CPCN application. As in the past, Commission acknowledgment of the plan should not be interpreted as an endorsement of any particular element, nor constitute approval of any resource acquisition contained in the Plan.[9]

[9] See Order No. 25260 (GNR-E-93-03) and Order No. 22299 which describes the Commission's role in the IRP process.

STAFF RECOMMENDATION

After review of PacifiCorp's 2013 IRP, Staff believes that the Company performed extensive analyses, gave reasonably equal consideration of supply- and demand-side resources, and provided acceptable opportunities for public input, resulting in an IRP that satisfies the requirements set forth in Commission Order Nos. 25260 and 22299. Staff, therefore, recommends that the Commission acknowledge the Company's 2013 IRP.

Respectfully submitted this 8th day of August 2013.

For: Neil Price
Deputy Attorney General

Technical Staff: Mike Louis

i:umisc:comments/pace13.5npml comments

Case Fact Sheets Summary Tables

Table M.1 – Core Case Definitions

Theme	Case	Gas Price	CO2 Price	Coal Price	RPS	Class 2 DSM	Other
Reference	C01	Medium	Medium	Medium	None	Base	n/a
	C02	Medium	Medium	Medium	State	Base	n/a
	C03	Medium	Medium	Medium	State & Federal	Base	n/a
Environmental Policy	C04	Low	High	High	None	Base	n/a
	C05	Low	High	High	State & Federal	Base	n/a
	C06	High	Zero	Low	None	Base	n/a
	C07	High	Zero	Low	State & Federal	Base	n/a
	C08	Low	High	High	None	Base	n/a
	C09	Low	High	High	State & Federal	Base	n/a
	C10	Medium	Medium	Medium	None	Base	n/a
	C11	Medium	Medium	Medium	State & Federal	Base	n/a
	C12	High	Zero	Low	None	Base	n/a
	C13	High	Zero	Low	State & Federal	Base	n/a
	C14	Medium	Hard Cap (Medium Gas)	Medium	State & Federal	Accelerated	n/a
Targeted Resources	C15	Medium	Medium	Medium	State & Federal	Accelerated	No CCCT
	C16	Medium	Medium	Medium	State & Federal	Base	Geothermal/RPS
	C17	High	Medium	Medium	State & Federal	Base	Market Spike
	C18	Medium	Hard Cap (High Gas)	Medium	None	Accelerated	Clean Energy
Transmission	C19	Medium	Medium	Medium	State & Federal	Base	Alt. to Segment D

Attachment A
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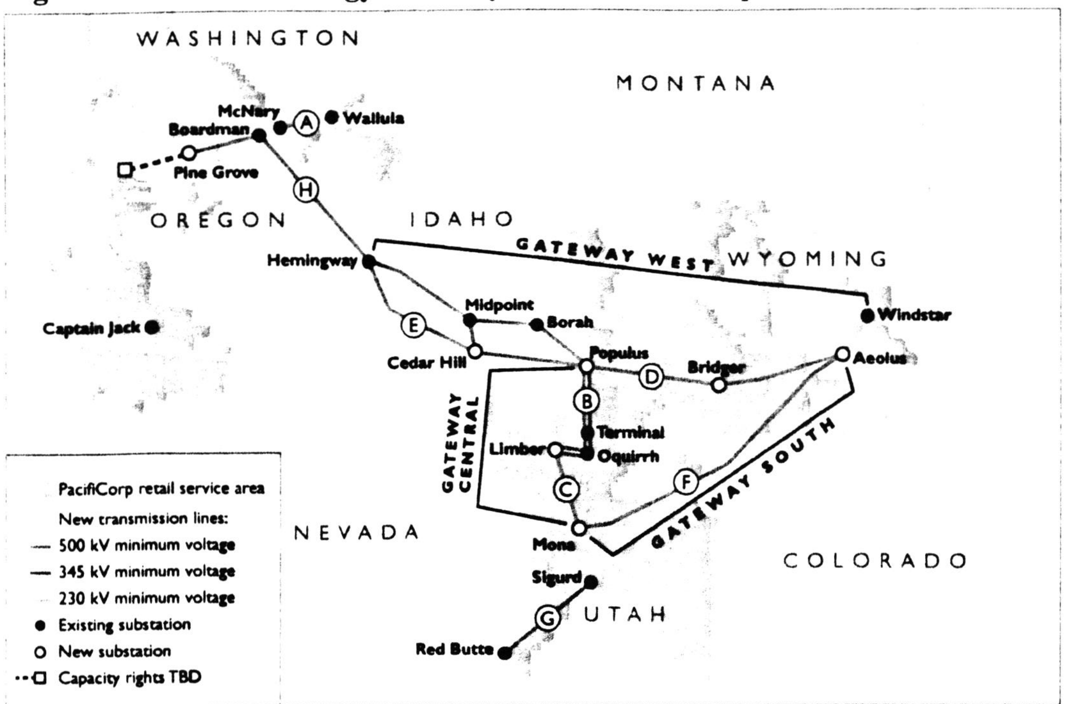
Figure 7.4 – Future Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

Table 7.5 – Energy Gateway Scenario Definitions

Scenario	Segments	Description
EG1	C and G	**Reference** – Mona-Oquirrh-Terminal, Sigurd-Red Butte
EG2	C, D, and G	**System Improvement** – 2013 Business Plan
EG3	C, D, E, G, and H	**West/East Consolidation** – Increase interchange between PACE and PACW
EG4	C, D, G, and F	**Triangle** – East side wind and improved reliability
EG5	C, D, E, G, H, and F	**Full Gateway** – All Energy Gateway segments

The 2013 IRP Action Plan

The 2013 IRP Action Plan identifies specific actions the Company will take over the next two to four years. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2013 IRP process. Table 9.1 details specific 2013 IRP action items by category.

Table 9.1 – 2013 IRP Action Plan

Action Item	12. Renewable Resource Actions
1a.	**Wind Integration** • Update the wind integration study for the 2015 IRP. The updated wind integration study will consider the implications of an energy imbalance market along with comments and feedback from the technical review committee and IRP stakeholders provided during the 2012 Wind Integration Study.
1b.	**Renewable Portfolio Standard Compliance** • With renewable portfolio standard (RPS) compliance achieved with unbundled renewable energy credit (REC) purchases, the preferred portfolio does not include incremental renewable resources prior to 2024. Given that the REC market lacks liquidity and depth beyond one year forward, the Company will pursue unbundled REC requests for proposal (RFP) to meet its state RPS compliance requirements. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard obligations. – Issue at least annually, RFPs seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for Oregon renewable portfolio standard obligations. As part of the solicitation and bid evaluation process, evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio standard obligations.
1c.	**Renewable Energy Credit Optimization** • On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.
1d.	**Solar** • Issue an RFP in the second quarter of 2013 soliciting Oregon solar photovoltaic resources to meet the Oregon small solar compliance obligation (Oregon House Bill 3039). Coordinate the selection process with the Energy Trust of Oregon to seek 2014 project funding. Complete evaluation of proposals and select potential winning bids in the

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	fourth quarter of 2013. • Issue a request for information 180 days after filing the 2013 IRP to solicit updated market information on utility scale solar costs and capacity factors.
1e.	**Capacity Contribution** • Track and report the statistics used to calculate capacity contribution from wind resources and available solar information as a means of testing the validity of the peak load carrying capability (PLCC) method.
Action Item	**13. Distributed Generation Actions**
2a.	**Distributed Solar** • Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity. Beginning in June 2014, as stipulated in the Order in Docket No. 11-035-104, the Company will file an Annual Report with program results, system costs, and production data. These reports will also provide an opportunity to evaluate and improve the program as the Company will use this opportunity to recommend changes. Interested parties will have an opportunity to comment on the report and any associated recommendations.
2b.	**Combined Heat & Power (CHP)** • Pursue opportunities for acquiring CHP resources, primarily through the Public Utilities Regulatory Policies Act (PURPA) Qualifying Facility contracting process. For the 2013 IRP Update, complete a market analysis of CHP opportunities that will: (1) assess the existing, proposed, and potential generation sites on PacifiCorp's system; (2) assess availability of fuel based on market information; (3) review renewable resource site information (i.e. permits, water availability, and incentives) using available public information; and (4) analyze indicative project economics based on avoided cost pricing to assist in ranking probability of development.
Action Item	**14. Firm Market Purchase Actions**
3a.	**Front Office Transactions** • Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017. – Resources will be procured through multiple means, such as periodic market RFPs that seek resources less than five years in term, and bilateral negotiations. – Include in the 2013 IRP Update a summary of the progress the Company has made to acquire front office transactions over the 2014 to 2017 forward period.
Action Item	**15. Flexible Resource Actions**

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4a.	**Energy Imbalance Market (EIM)** • Continue to pursue the EIM activities with the California Independent System Operator and the Northwest Power Pool to further optimize existing resources resulting in reduced costs for customers.
Action Item	**16. Hedging Actions**
5a.	**Natural Gas Request for Proposal** • Convene a workshop for stakeholders by October 2013 to discuss potential changes to the Company's process in evaluating bids for future natural gas RFPs, if any, to secure additional long-term natural gas hedging products.
Action Item	**17. Plant Efficiency Improvement Actions**
6a.	**Plant Efficiency Improvements** • Production efficiency studies have been conducted to satisfy requirements of the Washington I-937 Production Efficiency Measure that have identified categories of cost effective production efficiency opportunity. – By the end of the first quarter of 2014, complete an assessment of the plant efficiency opportunities identified in the Washington I-937 studies that might be applicable to other wholly owned generation facilities. – Prior to initiating modeling efforts for the 2015 IRP, determine a multi-state "total resource cost test" evaluation methodology to address regulatory recovery among states with identified capital expenditures. – Prior to initiating modeling efforts for the 2015 IRP, present to IRP stakeholders in a public input meeting the Company's recommended approach to analyzing cost effective production efficiency resources in the 2015 IRP.
Action Item	**18. Demand Side Management (DSM) Actions**

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7a.	**<u>Class 2 DSM</u>** • Acquire 1,425 – 1,876 gigawatt hours (GWh) of cost-effective Class 2 energy efficiency resources by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017. – Collaborate with the Energy Trust of Oregon on a pilot residential home comparison report program to be offered to Pacific Power customers in 2013 and 2014. At the conclusion of the pilot program and the associated impact evaluation, assess further expansion of the program. – Implement an enhanced consolidated business program to increase DSM acquisition from business customers in all states excluding Oregon. ▪ Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. ▪ Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. ▪ Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014. – Accelerate to the 2nd quarter of 2014, an evaluation of waste heat to power where generation is used to offset customer requirements – investigate how to integrate opportunities into the DSM portfolio. – Increase acquisitions from business customers through prescriptive measures by expanding the "Trade Ally Network". ▪ Base case target in all states is 3rd quarter 2014, with an accelerated target of 4th quarter 2013 – Accelerate small-mid market business DSM acquisitions by contracting with third party administrators to facilitate greater acquisitions by increasing marketing, outreach, and management of comprehensive custom projects by 1st quarter 2014. – Increase the reach and effectiveness of "express" or "typical" measure offerings by increasing qualifying measures, reviewing and realigning incentives, implementing a direct install feature for small commercial customers, and expanding the residential refrigerator and freezer recycling program to include commercial units. ▪ Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. ▪ Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. ▪ Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014. – Increase the reach of behavioral DSM programs: ▪ Evaluate and expand the residential behavioral pilot. ♦ Utah base case schedule is 2nd quarter 2014, with an accelerated target of 4th quarter 2013. ▪ Accelerate commercial behavioral pilot to the end of the first quarter 2014. ▪ Expand residential programs system-wide pending evaluation results. ♦ System-wide target is 3rd quarter 2015, with an accelerated target of 3rd quarter 2014. – Increase acquisition of residential DSM resources:

	▪ Implement cost effective direct install options by the end of 2013. ▪ Expand offering of "bundled" measure incentives by the end of 2013. ▪ Increase qualifying measures by the end of 2013. ▪ Review and realign incentives. ♦ Utah schedule is 1st quarter 2014 ♦ Washington base case schedule is 2nd quarter 2014, with accelerated target of 1st quarter 2014. ♦ Wyoming, California, and Idaho base case schedule is 3rd quarter 2014, with an accelerated target of 2nd quarter 2014 – Accelerate acquisitions by expanding refrigerator and freezer recycling to incorporate retail appliance distributors and commercial units – 3rd quarter 2013. – By the end of 2013, complete review of the impact of accelerated DSM on Oregon and the Energy Trust of Oregon, and re-contract in 2014 for appropriate funding as required. – Include in the 2013 IRP Update Class 2 DSM decrement values based upon accelerated acquisition of DSM resources. – Include in the 2014 conservation potential study an analysis testing assumptions in support of accelerating acquisition of cost-effective Class 2 DSM resources, and apply findings from this analysis into the development of candidate portfolios in the 2015 IRP.

<table>
<tr><td>7b.</td><td><u>Class 3 DSM</u>
Develop a pilot program in Oregon for a Class 3 irrigation time-of-use program as an alternative approach to a Class 1 irrigation load control program for managing irrigation loads in the west. The pilot program will be developed for the 2014 irrigation season and findings will be reported in the 2015 IRP.</td></tr>
<tr><th>Action Item</th><th>19. Coal Resource Actions</th></tr>
<tr><td>8a.</td><td><u>Naughton Unit 3</u>
Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division.
Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process.
Issue an RFP for engineering, procurement, and construction of the Naughton Unit 3 natural gas retrofit as required to support compliance with the conversion date that will be established during the permitting process.</td></tr>
<tr><td>8b.</td><td><u>Hunter Unit 1</u>
Complete installation of the baghouse conversion and low NO_X burner compliance projects at Hunter Unit 1 as required by the end of 2014.</td></tr>
<tr><td>8c.</td><td><u>Jim Bridger Units 3 and 4</u>
Complete installation of selective catalytic reduction (SCR) compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4 as required by the end of 2015 and 2016, respectively.</td></tr>
<tr><td>8d.</td><td><u>Cholla Unit 4</u>
Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency's Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives in the 2013 IRP Update.</td></tr>
<tr><th>Action Item</th><th>20. Transmission Actions</th></tr>
<tr><td>9a.</td><td><u>System Operational and Reliability Benefits Tool (SBT)</u>
60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT).
– For the 2013 IRP Update, complete additional analysis of the Energy Gateway West Segment D that evaluates staging implementation of Segment D by sub-segment.</td></tr>
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	– In preparation for the 2015 IRP, continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments.
9b.	**Energy Gateway Permitting** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: – Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years. – Segment H Cascade Crossing, complete benefits analysis in 2013. – Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission. Project Joint Permit Funding Agreement, projected through 2015.
9c.	**Sigurd to Red Butte 345 kilovolt Transmission Line** • Complete project construction per plan.
Action Item	**21. Planning Reserve Margin Actions**
10a.	**Planning Reserve Margin** • Continue to evaluate in the 2015 IRP the results of a System Optimizer portfolio sensitivity analysis comparing a range of planning reserve margins considering both cost and reliability impacts of different levels of planning reserve margin assumptions. Complete for the 2015 IRP an updated planning reserve margin analysis that is shared with stakeholders during the public process.
Action Item	**22. Planning and Modeling Process Improvement Actions**
11a.	**Modeling and Process** • Within 90 days of filing the 2013 IRP, schedule an IRP workshop with stakeholders to discuss potential process improvements that can more efficiently achieve meaningful cost and risk analysis of resource plans in the context of the IRP and implement process improvements in the 2015 IRP.
11b.	**Cost/Benefit Analysis of DSM Resource Alternatives** • Complete a cost/benefit analysis on the level of detail used to evaluate prospective DSM resources in the IRP. The analysis will consider the tradeoffs between model run-time and resulting resource selections, will be shared with stakeholders early in the 2015 IRP public process, and will inform how prospective DSM resources will be aggregated in developing resource portfolios for the 2015 IRP.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 8TH DAY OF AUGUST 2013, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-13-05, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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